Phased Project
Description of the Amendment

1.0 Introduction

BP West Coast Products, LLC, (the Certificate Holder) is requesting an amendment to the Site Certification Agreement dated December 21, 2004 (SCA) for the Cherry Point Cogeneration Project (the Authorized Project) to allow it the option of constructing the Cogeneration Project in two phases. Under the "Phased Project" scenario, the Phase I Facility would consist of an approximately 520-570 megawatt (MW) combined-cycle cogeneration facility, with two combustion gas turbines (CGTs), two heat recovery steam generators (HRSGs), and one steam turbine generator (STG). Phase II would consist of additions and modifications to the Phase I Facility to increase its total capacity to no more than the 720 MW originally authorized by the SCA.

This project description focuses on the Phase I Facility, highlighting the primary differences between it and the facility authorized by the original SCA. A summary table of these differences is provided as Table 6 at the end of this document.

The Phase I Facility would fit within the same footprint as the Authorized Facility, and with the exception of VOC emissions under maximum duct burning conditions (explained below), its construction and operation would have fewer environmental impacts than authorized by the original SCA.

The Phase II facility is described only conceptually in this document, as further additions or modifications to the facility that would increase its capacity to no more than 720 MW. The Certificate Holder assumes that the combined Phase I and Phase II facility would still occupy the same footprint as the Authorized Facility, and impacts associated with construction and operation would stay within the envelope considered in connection with the original SCA. If, after constructing the Phase I Facility, the Certificate Holder decided to go forward with Phase II, the Certificate Holder would provide the Council with detailed information about the configuration of Phase II. If further amendment of the SCA is required, the Certificate Holder would request it at that time.

2.0 Phase I Location and Land Use

The existing SCA authorizes construction of the Cogeneration Project on an approximately 33-acre site in the Heavy Impact Industrial area of unincorporated Whatcom County, located adjacent to the northeast corner of the BP Cherry Point Refinery. The Phase I Facility would occupy the same site and construction laydown areas would remain the same.

3.0 Phase I Electric Capacity and Steam Supply

The Phase I Facility would produce between 520 and 570 MW depending upon the specific CGT model selected. It is expected to provide up to 100 MW of electricity to the

Refinery, with the remaining electricity exported to the regional transmission grid via a new transmission line connected to the existing 230 kV BP transmission line that is adjacent to the BP Refinery.

The Phase I facility will be capable of exporting up to 1,200,000 pounds per hour of steam to the BP Refinery at a temperature of 750 degrees F and a pressure of 650 psia. On average, the project is expected to provide approximately 510,000 pounds per hour of steam to the Refinery. The Refinery will maintain backup boilers to service its steam demand in the event that one or both of the CGTs are not operating. To ensure steam redundancy required of the Cogen project, larger duct burners will be installed in the Phase I facility and backup boilers will be placed on hot standby when one gas turbine is down for maintenance.

Table 1: Estimated Maximum Annual Energy Output
(Average Ambient Conditions @ 50^0F, 65% RH and 94% Capacity factor)

Component	Authorized 3x1 720MW Project*	Phase I Project, ca. 520MW with GE 7FA turbines	Phase I Project, ca. 570MW with Siemens SGT6-5000F turbines
Gross Power Output, MWH	6,083,574	4,414,000	4,825,000
Auxiliary Power Used by Cogeneration Project, MWH	-146,325	-132,000	-132,000
Net Power Output, MWH	5,937,249	4,282,000	4,693,000
Steam Export to Refinery, klb/yr, 650 psia, 510 kpph	4,200,000	4,200,000	4,200,000

* Authorized Project values from ASC Section 3.8, Table 3.8-4

4.0 Phase I Equipment

The Phase I facility would be configured with two natural gas-fired CGTs. Each CGT would be equipped with a HRSG with supplemental duct-firing capability. Steam produced from the HRSGs would be sent to a single STG with process extraction and condensing capability. Two alternative equipment layouts are under consideration. See Figure 2-3 and Figure 2-4, attached.

The Phase I Facility would use either GE 7FA or Siemens SGT-6 5000F (the new version of the Siemens 501F) CGTs. Each CGT would have a nominal power output of 173 MW or 198MW, respectively, at 50F. The CGTs would be equipped with Dry Low NOx combustion systems. Air emission information is provided for both turbine models.

The Phase I Facility would have two HRSGs featuring a triple-pressure reheat design. Each HRSG would be equipped with duct burners for supplementary firing with either natural gas or refinery fuel gas treated to the same sulfur levels as natural gas.

The maximum duct firing capacity for each Phase I Facility HRSG would likely be between 450-600 MMBtu/hr, which is larger than the duct burners in the Authorized Facility. These larger duct burners are needed to provide for a portion of the required steam redundancy in the event that one gas turbine is out of service.

The HRSGs would also be equipped with a selective catalytic reduction (SCR) NOx emission control system and CO oxidation catalyst. The Phase I facility would use aqueous ammonia rather than anhydrous ammonia as authorized by the existing SCA. This change should reduce the potential for offsite ammonia exposure. The aqueous ammonia system would consist of ammonia storage, transfer, vaporization and injection subsystems.

The Phase I facility would have a single STG. The STG would have a maximum gross power output of approximately 200 MW, but its actual output would vary upon the number and loading of CGTs operating, the amount of steam going to the Refinery, and the amount of duct firing occurring.

5.0 Electrical Interconnection

The Phase I facility will have a switchyard consisting of 230 kV breakers and associated controls, two outgoing 230kV circuits to the BPA transmission grid and two outgoing 230kV circuits to the Refinery. The outgoing lines to BPA would consist of the same double-circuit 0.8 mile long transmission line from the 230 kV switchyard to the interconnection point at Kickerville Road as allowed in the existing SCA. No additional modifications to the local BPA system would be required for the Phase I facility.

6.0 Phase I Fuel Use and Supply

The CGTs would be fueled by natural gas, and would not use backup fuels. The estimated fuel consumption at various operating conditions is provided below.

Table 2: Estimated fuel consumption with 510 Mlb/hr steam export to refinery
(Average Ambient Conditions @ 50^0F, 65% RH, 94% Capacity factor)

	Hourly Fuel Consumption, MMBtu LHV	Annual Fuel Consumption, MMBtu LHV
Phase I Facility with either:		
GE 7FA turbines	3,700	30,446,000
Siemens SGT6-5000F turbines	4,100	33,942,000
3x1 Authorized Project, GE 7FA turbines*	4,846	42,457,356

* ASC Section 3.8 Tables 3.8-3 and 3.8-5

The Ferndale Pipeline would deliver natural gas to the Cogeneration Project site at a pressure of 500-550 psig. The owner and operator of the Ferndale Pipeline had previously anticipated installing additional compression at the Refinery, but now plans to install a compressor station near the U.S.-Canada border instead. The owner and operator of the pipeline will obtain whatever permits and approvals are required to construct and operate this compressor station.

The HRSG duct burners could burn either natural gas or refinery fuel gas that would be treated to meet the same specifications as natural gas. A table showing typical natural gas and refinery fuel gas composition is attached as Table 3. As can be seen from this table, refinery fuel gas has less methane and more hydrogen, ethane, propane and butane than pipeline quality natural gas. Both natural gas and refinery fuel gas have sulfur compounds in the form of H2S and mercaptans. The refinery fuel gas will be treated to remove sulfur in excess of the quantity normally found in natural gas before combustion in the Phase I facility duct burners.

Table 3, Typical Gaseous Fuel Properties

Component, mol%	Natural Gas	Refinery Fuel Gas
H_20	Note 1	0.0
Oxygen	0.0	0.0
Nitrogen	0.3	0.8
Carbon monoxide	0.0	0.1
Carbon dioxide	0.0	0.2
Hydrogen sulfide	0.0	0.0
Hydrogen	0.0	19.6
Methane	96.9	50.3
Ethane	2.0	10.7
Ethylene	0.0	0.9
Propane	0.6	9.8
Propylene	0.0	1.8
Isobutane	0.1	1.9
n-Butane	0.1	2.5
Butenes	0.0	0.7
Isopentane	0.0	0.4
n-Pentane	0.0	0.2
Hexane +	0.0	0.1
Total	100.0	100.0

Total Sulfur Content , gr/100 DSCF	Annual Average	Short Term Min	Short Term Max
Natural Gas (Note 2)	0.9	0.65	1.65
Refinery Fuel Gas	0.8	0.65	1.60

Notes:

1. Water content in natural gas less than or equal to 7 pounds per million cubic feet.
2. Natural gas sulfur includes 0.3 gr/100 DSCF odorant added at Sumas, WA.

7.0 Water Usage and Waste Water Discharge

The Phase I Facility will use less water than the Authorized Project would have used. Table 4 below shows predicted annual average water usage:

Table 4: Predicted Annual Average Water Usage, gpm

	Authorized 3x1 Project*		Phase 1 Facility	
	Base Case	Worst Case	Base Case	Worst Case
Average Intalco re-use water flow	2,780	2,780	2,780	2,780
Annual Average Water Consumed by Cogen	-2,244	-2,316	-1,700	-2,000
Refinery Water Consumption Reduction	20	20	20	20
Annual Average Water Saved	556	484	1,100	800

* From ASC Appendix D, Table 6.2-1

With the water re-use project described in the project ASC, the Phase I Facility will roughly double the water savings from the Nooksack River to 800-1,100 gpm of water on average, when compared to the Authorized Project.

The Cogeneration Project will send wastewater to the Refinery water treatment system. The Phase I Facility will generate less waste water than the originally authorized facility as shown in Table 5 below.

Table 5: Predicted Wastewater Flows, gpm

	3x1 Authorized Project*		Phase I Facility	
	Average	Peak	Average	Peak
Cooling Tower Blowdown	131-203	400	160-200	300
Demin Plant Regeneration	54	300	54	300
Equipment Drain and Washdown, Oily Water	5	50	0	0
Total	190-262	459-508**	214-254	354-490**

* From ASC Appendix D Table 7.1-1.
** Peak flows are typically not coincident, so ranges shown are based on different combinations of peak and average flows.

The amount of cooling tower blowdown varies depending upon cycles of concentration used. For the 3x1 Authorized Project, the blowdown wastewater stream would be about 131 gpm at 15 cycles of concentration and about 203 gpm at 10 cycles of concentration. The total pounds of constituents in the wastewater are the same regardless of blowdown rate but concentration of these constituents increases with cycles of concentration.

In the original permit application the Certificate Holder used 15 cycles of concentration when calculating the impact on the refinery wastewater treatment system, and 10 cycles when calculating fresh water requirements.

It is anticipated the Phase I Facility cooling tower will be run at 8-10 cycles of concentration, which is similar to the operation of refinery cooling towers. Fresh water and wastewater flows in this amendment description reflect this type of cooling tower operation.

The type of constituents found in waste water from the Phase I Facility is expected to be the same as those found in wastewater from the Authorized Project, since the generating process used is the same. The pounds of constituents in Phase I Facility wastewater will be less than those from the Authorized Project, as the Phase I Facility water usage is less.

As an additional water conservation measure, water from Phase I Facility equipment drains and washdowns will be routed to an oily water separator, and clean water will be pumped to the cooling tower basin rather than being pumped directly to the refinery wastewater treatment system. This will reduce the quantity of fresh water used by the cooling tower.

8.0 Air Emissions

Total criteria pollutants produced by the Phase I Facility would be less than those authorized by the original SCA and PSD Permit. On a maximum potential to emit basis, each of the criteria pollutants are the same or less with the exception of VOCs. Duct burners have higher VOC emission factors per MMBtu of fuel than combustion gas turbines, so VOCs produced by the higher duct burner firing more than offset the reduction in VOCs obtained by reducing the CGTs from three to two. As was the case with the Authorized Project, short and long term modeled emissions impacts remain below regulatory thresholds, including Significant Impact Levels (SILs). Detailed emission and air quality information is presented in the accompanying PSD Amendment Application and SEPA Checklist.

9.0 Phase I Construction Schedule and Capital Costs

Assuming a construction start date of May 2007, the Phase I facility could commence commercial operation in summer 2009.

Total capital costs for the Phase I facility are currently estimated to be approximately $400 million, but this figure is subject to change.

Table 6: Comparison of Project Authorized by Existing SCA
with Proposed Phase I Facility

Facility Design	3x1 Authorized Project	Phase 1 Facility
Maximum Electrical Output	720 MW	520-570 MW
Electricity to Refinery	85 MW	100 MW
Steam to Refinery	770,000 lbs per hour (max.) 510,000 lbs per hour (avg.)	1,200,000 lbs per hour (max.) 510,000 lbs per hour (avg.)
Gas Turbines	Three GE 7FA	Two GE 7FA, or Two Siemens SGT6-5000F
Number of HRSGs	Three	Two
Duct Burner maximum firing rate	315 MMBtu/Hr total (105 MMBtu/Hr each)	900-1200 MMBtu/Hr total (450-600 MMBtu/Hr each)
Duct Burner fuel	Natural Gas	Natural Gas or Refinery Fuel Gas Treated to Equivalent Sulfur Specification
Form of Ammonia	Anhydrous	Aqueous
Building Code Used	UBC-97	IBC-2003
Capital Cost	$580 million	$400 million
Water Use (average)	2,244-2,316 gpm	1,700-2,000 gpm
Process Waste Water	190-262 gpm average 459-508 gpm peak	214-254 gpm average 354-490 gpm peak

Impacts	3x1 Authorized Project	Phase 1 Facility
Potential to Emit Air Emissions – Criteria Pollutants, Tons per Year (TPY) “Potential to Emit” emissions are evaluated at 8760 hrs/year at maximum duct burning	GE 7FA Turbines: TPY NOx: 234 CO: 158 SO2: 51 PM10: 262 VOC: 43	GE 7FA Turbines: TPY NOx: 201 CO: 158 SO2: 47 PM10: 262 VOC: 58 Siemens SGT6-5000F Turbines: TPY NOx: 220 CO: 102 SO2: 51 PM10: 194 VOC: 57
Expected Air Emissions, taking into account emission reductions at refinery, Tons per Year (TPY) Expected Emissions reflect more realistic operations and consider the beneficial impacts of refinery boiler emission reductions. Two cases are considered, the Full Dispatch case where the Cogen runs year-round except for maintenance, and a Partial Dispatch case where the Cogen is offline about 60 days per year.	GE 7FA Turbines: TPY NOx: -318 CO: +27 SO2: +43 PM10: +84 VOC: +25 Total: -143	GE 7FA Turbines: Full Dispatch TPY / Partial Dispatch TPY NOx: -355 / -350 CO: 9 / 46 SO2: 28 / 25 PM10: 67 / 59 VOC: 23 / 25 Total: -228 / -195 Siemens SGT6-5000F: Full Dispatch TPY / Partial Dispatch TPY NOx: -353 / -339 CO: 21 / 16 SO2: 29 / 33 PM10: 38 / 42 VOC: 19 / 22 Total: -246 / -226

Table 6, Continued

Non-Project Facilities	3x1 Authorized Project	Phase 1 Facility
Ferndale Pipeline Compression Station Location	Compressor station at Refinery	Compressor state near U.S.-Canada border
BPA interconnection	Loop in circuit from existing Custer-Intalco line, with possible third circuit needed from project site to Custer within existing BPA right of way.	Loop in circuit from existing Custer-Intalco line; no other modifications required.
Refinery interconnection	Three 230 kV/69kV transformers and three 69 kV lines to refinery substations.	Two 230 kV lines to refinery substations.